



**Pacific Gas and
Electric Company®**

Diablo Canyon Power Plant P. O. Box 56
Avila Beach, CA 93424

July 13, 2012

PG&E Letter DCL-2012-637

Dr. Bruce Gibson
Supervisor, District 2
San Luis Obispo County
San Luis Obispo, CA 93401

Response to June 20, 2012, Request for Information

Dear Dr. Gibson:

Please find attached a response to the questions that you presented in your June 20, 2012 letter associated with the Central Coastal California Seismic Imaging Project (CCCSIP).

After you have had time to review the responses, we are interested in bringing in our science team leads to expand upon the answers and address any other questions that may be generated from this response.

We look forward to further discussions on these important studies.

Sincerely,

L. Jearl Strickland
Director, Nuclear Projects
805-781-9785 (office)
805-441-4208 (cell)
LJS2@pge.com (email)

Enclosure

**Pacific Gas and Electric Company's Response to
Bruce Gibson June 20, 2012, Request for Information**

Introduction

In 2008, the California Energy Commission (CEC) completed an assessment of the vulnerability of Diablo Canyon Power Plant (DCPP) to a major disruption due to a seismic event or plant aging, as required by CA Assembly Bill (AB)1632 (Blakeslee, Chapter 722, Statutes of 2006). As a result of that assessment, the CEC recommended that Pacific Gas and Electric Company (PG&E) complete additional seismic studies using three-dimensional (3D) seismic reflection mapping and other advanced geophysical techniques to explore fault zones near DCPP. In addition, PG&E funded U.S. Geological Survey research that reevaluated more than 20 years of earthquake data that lead to the discovery of the Shoreline fault zone in 2008. In 2009 and 2010, both the California Public Utilities Commission (CPUC) and the California Coastal Commission (CCC) directed PG&E to complete the advanced studies recommended in AB1632 as part of their license renewal feasibility studies and reviews. The CPUC established an Independent Peer Review Panel (IPRP) in 2010 to provide an independent peer review and comment on these proposed seismic studies.

The PG&E High Energy Seismic Survey (HESS) program is one task in a series of comprehensive geologic/ geophysical investigations that PG&E has been conducting as part of the Central Coastal California Seismic Imaging Project (CCCSIP). The CCCSIP represents the continuation of earlier studies initiated in 2008 and 2009 that specifically addressed the Shoreline fault zone. The CCCSIP involves government, academic and industry partners including the National Science Foundation, Columbia University/ Lamont-Doherty Earth Observatory, the Scripps Institute of Oceanography, the University of Nevada/Reno, the CSU Monterey Bay Sea Floor Mapping Lab, Fugro Consultants Inc., Nodal Seismic, Bird Seismic Services, Fairfield Nodal, NCS SubSea, and others in order to collect the highest quality seismic and geophysical data using state-of-the-art technologies. In recognition of the substantial costs involved to perform these types of studies, PG&E has adopted a systematic, nested approach to conduct the CCCSIP. Regional scale surveys are used to identify areas for more comprehensive, high-resolution site-specific investigations.

In addition to the integration and interpretation of the diverse geologic and geophysical data sets collected as part of the CCCSIP, there are additional challenges and demands that are not usually encountered in industry work. These include the need for Nuclear Quality Assurance / Quality Control (QA/QC) oversight and documentation (including extensive software and hardware calibration and validation), participatory peer review requirements consistent with the needs of the informed technical community (including the CPUC IPRP, US Nuclear Regulatory Commission (NRC) and Senior Seismic Hazard Analysis Committee (SSHAC) processes), public transparency, and extraordinary environmental and permitting constraints.

The following comments are presented in response to the specific issues listed in Dr. Gibson's letter to PG&E dated June 20, 2012.

Request 1

The overall design approach for both the offshore and transition zone surveys should be described. The survey design discussion should explain how survey acquisition parameters, data processing sequence, and interpretation products were chosen and how these three elements are integrated.

Response 1

Initial IPRP review of PG&E'S plans focused on the geologic targets or fault segments to be surveyed and the potential impact of that information on the seismic hazard evaluation for DCP. Those geologic targets and their potential impacts on the DCP seismic hazard analysis were identified in PG&E's 2011 Shoreline Fault Zone report to the NRC. Updated ground motion models used in the NRC Report identified strike-slip earthquakes along the Shoreline and Hosgri fault zones as well as reverse-slip earthquakes on the Los Osos and San Luis Bay fault zones as the key contributors to seismic hazard at DCP.

To better constrain the four main parameters needed for a seismic hazard assessment: geometry (fault length, fault dip, down-dip width), segmentation, distance offshore from DCP, and slip-rate, PG&E conducted a series of sensitivity studies to document which of those four sets of parameters had the greatest impact on reducing the overall uncertainty for hazard estimates. The offshore target areas and the parameters to be addressed by the CCCSIP are listed in Table 1. These issues determined the design goals of both the Low and High Energy 2D and 3D Seismic Surveys.

Table 1 List of Targets for Offshore Geophysical Studies

Target Region	Technical Issue	Method
Hosgri-San Simeon step-over	Geometry of the step-over. Is it really a segmentation point?	Low Energy 2D / 3D High Energy 3D
Hosgri fault offshore DCP	Slip Rate	Low Energy 2D / 3D
	Dip	High Energy 3D Regional geophysical studies
Shoreline fault zone	Geometry of northern segment	Low Energy 2D / 3D High Energy 3D

Target Region	Technical Issue	Method
	Southern extent	Low Energy 2D / 3D
	Slip Rate	Low Energy 2D / 3D
Hosgri-Shoreline Intersection	Structural relationship between the Hosgri and Shoreline fault	Low Energy 2D / 3D High Energy 3D
Los Osos fault	Structural relationship between the Hosgri and Los Osos fault	Low Energy 2D / 3D High Energy 3D
	Slip rate	Low Energy 2D / 3D
San Luis Bay fault	Dip	Low Energy 2D / 3D High Energy 3D

The overall design approach for both the LESS and HESS studies is dictated by the technical goals to be addressed as well geographic setting of the site (e.g., water depth, navigation obstacles), the capabilities of the survey vessel(s) and equipment, as well as environmental and permitting constraints

As shown in Table 1, the 2D and 3D LESS studies of the Shoreline fault conducted in 2010 and 2011 focused on the northern and southern ends, near Point Buchon and within San Luis Bay, respectively. These surveys addressed the shallow structure of the Shoreline fault as well as identified possible piercing points or areas where the Shoreline fault intersected recent geomorphic features in order to determine fault slip rates.

Both the LESS studies and the onshore 2D/ 3D seismic surveys in 2011 tested the feasibility of conducting further seismic profiling along the continental shelf offshore of DCP. Much of the Tertiary rocks within the onshore Irish Hills and offshore continental shelf are underlain by the highly chaotic Mesozoic Franciscan Formation. As discussed in Request 2, results from onshore seismic surveys in 2011 provided an important pilot test or feasibility for conducting additional HESS surveys offshore. Could PG&E, in fact, use 3D seismic survey techniques to image structures within the Franciscan? Based on these initial results, the subsurface structures are truly complex and intrinsically 3D; 2D seismic reflection data acquisition is not a reliable or appropriate approach to accurately image crustal structure in this area. Systematic 3D data acquisition with rigorous population of common mid-point (CMP) bins over a wide range of offsets and azimuths is necessary to obtain spatially accurate images of crustal structure in CCCSIP study area.

Based on the lessons learned from the 2011 onshore survey and advice from PG&E's contractors concerning marine 3D multichannel data acquisition, PG&E's response to Request 3 discusses the basic seismic acquisition parameters, such as spatial sampling interval and maximum source-receiver offset, needed to image the target structures listed in Table 1 at depth. One of the major survey design issues is the close proximity of the geologic targets to shore. The central section of the Shoreline fault lies within the Transition or Intertidal Zone in water depths less than 25 m. As discussed in Request 4, safety concerns about operating large vessels in shallow water with rocks and kelp beds precluded conventional approaches to seismic imaging. As a result, other strategies, including high resolution helicopter aero magnetics and marine gravity surveys as well as the deployment of marine nodes were developed to image the Transition Zone.

In order to constrain the deeper geometry of fault zones and image to the depths at which earthquake are occurring, 3D HESS surveys require the use of 6 to 8 km long streamers. This influences the orientation of the survey racetrack design. While the ideal seismic survey orientation is generally perpendicular to structure (dip lines), the close proximity of both the Hosgri and Shoreline faults to shore in the region between Point Buchon and Point San Luis (less than 1 streamer length) requires orienting survey lines parallel to the strike of the fault (strike lines) instead of perpendicular to the fault (dip lines). The overall width or footprint of these strike line survey tracks, however, is still influenced by the closest approach to shore. As shown in Figure 1, HESS Survey Racetracks or Boxes 1, 2, and 3 were designed to account for these geometric constraints.

As shown in Figure 1, HESS Survey Box 4 in Estero Bay is oriented to be roughly perpendicular to the strikes of the Shoreline, Los Osos and Hosgri faults and provides an opportunity to conduct dip survey lines in this area. This would provide a broader azimuthal coverage of complex geologic structures in the area, consistent with PG&E's response to Request 5.

The data acquisition and processing is addressed in PG&E's response to Request 6. Initially, data from each of the offshore, transition zone and onshore 3D surveys will be collected and processed independently. Accordingly, the first phase of the survey data acquisition planning is focused on producing data sets in an industry standard SEG-Y data format that be integrated at a later date. Post-cruise, the latest industry processing toolkits will be used to produce both 3-D prestack time migration (PSTM) and prestack depth migration (PSDM) imagery. This processing will take place in Houston, Texas and will be contracted through an industry processing shop such as Fugro Seismic Imaging and/or GeoTrace. Recent advances in 3D tomography and full waveform inversion (FWI) techniques will also be applied to these new data.

Once the seismic data are processed, interpretation teams consisting of geoscience professionals with expertise in specific areas (e.g., seismic interpretation, structural geology) will be assembled to integrate and interpret data following the delivery of final processed data. In addition to individual SEG-Y files, data will be merged in a Kingdom

Suite 3D volume or cube to facilitate analysis and visualization of data for interpretation and further analysis.

Request 2

The offshore and transition zone survey design process should analyze results of recently-conducted land surveys to confirm the adequacy of acquisition parameters and processing flow.

Response 2

The major findings from the 2011 onshore seismic reflection survey in the Irish Hills are:

- (1) Successful imaging of the Franciscan basement can be accomplished, contrary to previous expectations
- (2) The identification of swept frequency and geophone spacing parameters necessary to capture both shallow and deep imaging
- (3) There is a higher expectation of success in imaging the Transition Zone through the use of onshore and offshore seismic sources

The following sections provide a more detailed discussion of these results.

Proprietary seismic reflection data within the greater Irish Hills owned by ConocoPhillips was licensed and reprocessed to determine the effectiveness of several types of seismic sources and recording configurations. The results of the ConocoPhillips data analyses were used to define the 2011 2D onshore testing and data acquisition program in the Irish Hills.

The primary findings from the analyses of the ConocoPhillips data are presented first, followed by a summary of the findings from the 2011 2D onshore testing and data acquisition program in the Irish Hills

1984 ConocoPhillips Data

ConocoPhillips acquired Dynamite data from one line in the central portion of the Irish Hills north of the DCPD property. Most of the ConocoPhillips line was located in Tertiary rocks, with the north end of the line extending about 1 km north of the southern Edna fault trace into Franciscan rocks. ConocoPhillips acquired data from six lines in the Irish Hills although five of the six lines were located east of the DCPD property. Three of the ConocoPhillips lines used Dynamite and three of the lines used VibroseisTM sources (Table 2).

Table 2 1984 ConocoPhillips Reflection Line Acquisition Parameters

Line Number	Line Name	Datum (ft)	Fold	Source	Channels	Group Interval (ft)	Shot Interval (ft)	Length (s)
1	p6502-1	800	24	Vibroseis™	96	82.5	165	4
3	p6502-3	800	24	Vibroseis™	96	82.5	165	4
4	p6502-4	200	24	Vibroseis™	96	82.5	165	4
6	p6502-6	800	24	Dynamite	96	110	220	4
9	p6598-9	200	24	Dynamite	96	110	220	4
13	p6598-13	1600	24	Dynamite	96	110	220	4

The ratio of signal to noise in the data is a function of acquisition parameters (Table 2), as well as the source and receiver configurations (Table 3). The deep shot holes and large charge (10 lb) used for line 13 (Table 3) produces the best overall signal quality, but the resolution of deeper structure is compromised by the high frequency (28 Hz) geophones used to record the Dynamite source and the limits of the maximum offsets attained with the 96 channel recording systems (Table 3). Also, there were many dead channels and frequency strong coherent electrical noise in most of the Dynamite shot records that further decreased signal strength.

Table 3 1984 ConocoPhillips Reflection Line Source and Receiver Configurations

Line Number	Line Name	Source	Sweep (Hz) or charge (lb)	Source Configuration	Geophone	Offset range (ft)
1	p6502-1	Vibroseis™	18-80 (12 s)	4 Failing Y-900	10 Hz	330-4208
3	p6502-3	Vibroseis™	18-80 (12 s)	4 Failing Y-900	10 Hz	330-4208
4	p6502-4	Vibroseis™	18-80 (12 s)	4 Failing Y-900	10 Hz	330-4208
6	p6502-6	Dynamite	0.5 lb	9 5 ft holes	28 Hz	110-5280
9	p6598-9	Dynamite	0.5 lb	9 5 ft holes	28 Hz	110-5280
13	p6598-13	Dynamite	10 lb	1 25 ft hole	28 Hz	110-5280

The sequence of steps in processing the data (Table 4) was designed and adjusted to evaluate signal quality as a function of frequency. Several high-frequency upper limits were selected for band pass filtering and the data stacked to determine the maximum frequency that produced the best signal-to-noise ratio. Although the Dynamite source

noise dominated at frequencies greater than 50-60 Hz and at frequencies greater than 40 Hz for times later than 2.3 to 2.5 seconds.

Table 4 1984 ConocoPhillips Data Processing Sequence

Step	Description
1	Reformat field SEG-Ydata
2	Vibroseis cross-correlation Sample rate 2 ms
3	Geometry definition (Vibroseis TM and Dynamite data)
4	Pick first breaks; Calculate Refraction Statics; 1 Layer Model; VO is 3000 feet/sec Datum is 200/800/1600 feet, replacement velocity is 7500/8000 feet/second
5	Trace edits and reversals
6	Amplitude recovery $T^{1.2}$, Air blast attenuation
7A	Dynamite data only: Surface consistent deconvolution, operator 160ms, gap 18 ms, time variant spectral whitening, 6/12-57/65 Hz frequency limits determined from spectral analyses and stacking tests of the data, multiple gate equalization
7B	Vibroseis TM data only: Time variant spectral whitening, 8 - 80 Hz frequency limits, one gate equalization
8	Statics to floating datum
9	Interactive velocity analysis; Residual statics surface consistent; Interactive velocity analysis; Residual statics surface consistent; CDP trim statics
10	Final normal moveout; Initial mute; 500 ms agc
11	Flat datum statics, datum varies as per Table 1, VR is 7500/8000 fps
12	Create final unfilterd stack cdp stack 1/root(n) Time Variant Bandpass filter: For: Vibroseis TM data 10/18-55/65 hz. 0.0 - 1.7 sec. 8/18-35/45 hz. 2.3 - 4.0 sec. Fx predictive deconvolution, Trace balance For: Dynamite data 10/15-50/60 hz. 0.0 - 2.0 sec. 8/13-35/45 hz. 2.5 - 4.0 sec. Fx predictive deconvolution, Trace balance Output Final stack in SEG-Y format

The 28-Hz geophones used for acquisition of lines 6, 9, and 13 (Tables 2 and 3) reduce resolution at two-way travel times greater than 2.5 seconds because the stack tests revealed that there is little signal at times greater than 2.5 seconds in the Dynamite data at frequencies greater than 40 Hz (step 12 in Table 4). Because the frequency-dependent stacking tests showed that there is little signal in the Dynamite data at frequencies > 60 Hz, there is no need to use high-frequency geophones to acquire data in this area. Consequently, improved signal-to-noise would have been obtained for lines 6, 9, and 13 for depths > 8000 ft simply by using 10-14 Hz geophones, which have

good response characteristics to > 60 Hz. In fact, the Vibroseis™ data generally produced better images of folded Tertiary structure using 10 Hz geophones in the first 1.7 seconds of the section than the Dynamite data using 28 Hz geophones (step 12 in Table 4) because the wider frequency bandwidth of significant signal-to-noise with the lower frequency geophones made it possible to consistently produce a more compact wavelet and obtain better overall resolution of even shallow reflectors than the Dynamite data acquired with high-frequency geophones. The Vibroseis™ data were also acquired with a shorter group and source spacing that also decreased aliasing in regions of steep dip relative to the Dynamite data.

Geologic mapping along the ConocoPhillips line showed little relationship between observed mapped dip directions and angles and shallow apparent dips in the ConocoPhillips seismic reflection data. Consequently, a key requirement in the specification of data acquisition parameters for the 2011 field program was to include sufficiently high-resolution data acquisition parameters to properly resolve shallow, often steep dips observed in many areas of the Irish Hills.

2011 Onshore 2D Seismic Reflection Field Program

Permitting inquiries revealed that the only permitted sources would be surface sources and that drilling and explosive sources could not be permitted. Consequently, the seismic sources available for the 2011 onshore seismic reflection field program were Vibroseis™ and impact surface sources. Permitting restrictions limited source positions to roads, precluding the types of regular source geometries required to properly populate CMP bins as a function of offset and azimuth and conduct rigorous 3D imaging tests. Permits for seismic operations on public areas restricted both sources and receivers to road right-of-ways. Consequently, limited 3D imaging testing was restricted to private properties where private landowners permitted deployment of regularly-spacing receiver 2D arrays away from roads.

As is typical in the oil and gas industry when both shallow high-resolution imaging of young faults and imaging deep structures and/or reservoirs are required, two data acquisition programs were designed to meet each of these objectives. Since permitting restricted data acquisition primarily to 2D imaging along roads, both data acquisition programs were run along the same routes when possible to provide resolution of both shallow and deep structure; the large Vibroseis™ trucks could not always access areas accessible to the AWD and the AWD did not operate on some of the roads used by the Vibroseis™ trucks, so there is not uniform overlap in all areas of the two data acquisition programs.

The shallow velocities in the Tertiary Pismo syncline along ConocoPhillips line 13 were used along with a maximum frequency of 50 Hz to determine that a 30-ft group spacing would avoid aliasing associated with steep dips and surface wave aliasing for a maximum surface wave frequency of 25 Hz (surface wave amplitudes decreased substantially above 25 Hz). A third-generation 450-lb accelerated weight drop (AWD)

source was selected for shallow-high-resolution imaging tests and 2D production. This source could adjust its output force with adjustable nitrogen spring pressure so that it could operate on weak asphalt surfaces that had lost their bonding agents without producing any deflection of the road surface to ensure compliance with permits (permit compliance required no perceptible road deflection as measured with a 12-ft straight edge). The 450-lb AWD was also able to access narrower roads than large Vibroseis™ trucks to obtain shallow high-resolution data in these regions.

The 2011 field program began with a week of source testing on the DCPD facility to determine optimal production source parameters. Real-time field processing with a 2D 400-channel networked cable system was used to assess source and acquisition using 30-ft group intervals and 14 Hz geophones. AWD and Vibroseis source monitoring systems were used to measure near-source signatures and ensure precise synchronization of 4-5 Vibroseis™ trucks. Testing showed that four synchronized 64,000-lb Hemi-60 Vibroseis™ trucks provide excellent signal at offsets at least as far as 6 km. Specific Vibroseis™ testing systems were used to determine the sweep parameters that produced consistent phase lock between drive and output in a variety of surface conditions to ensure Vibroseis™ sweep stability and consistency across the entire project area. A long-duration linear sweep of 24 seconds from 5 to 60 Hz produced the best combination of good consistent long offset (> 6 km) signal-to-noise with a broad frequency bandwidth that was achievable across all the diverse geologic units in the Irish Hills necessary to achieve consistent source frequency bandwidth imaging of intermediate and deeper structure.

Initial testing within the DCPD property with the AWD showed that steep dips were generally confined to depths of < 2-3 km and that coherent 30 Hz signals from the DCPD turbines were very large within several km of the DCPD. A station spacing of 120-ft was used for the nodes that would record the large Vibroseis™ sources since it was apparent that deeper dips were generally not as steep as shallow thin-skinned structure and that deeper imaging might require restricting the data to the 5- < 30 Hz frequency bandwidth to achieve consistent signal to noise at depths of 8-18 km. A Vibroseis™ source spacing of 120 ft was used in most areas; this was decreased to 60 ft in areas where undershooting was required.

2011 Onshore Field Program Findings

Strikes and dips varying rapidly, both horizontally and in depth to 2 to 4 km throughout nearly all regions of the Irish Hills encompassed by the 2011 onshore seismic reflection program. The seismic imaging problem is truly complex and intrinsically 3D; 2D seismic reflection data acquisition is not a reliable or appropriate approach to accurately image crustal structure in this area. Systematic 3D data acquisition with rigorous population of CMP bins over a wide range of offsets and azimuths is necessary to obtain accurate images of crustal structure in the Irish Hills and adjacent areas. Multiple high-energy data acquisition geometries and source configurations are required to achieve image objectives for shallow and deep structure. The 30-ft group and source spacing used

with the AWD source and > 300 channels effectively imaged shallow (0-2 km) steep dips at all locations, except where bedding was essentially vertical, to maximum frequencies of 50 Hz. This data acquisition configuration imaging faults from the surface to 1-2 km depth identified in previous paleoseismic investigations within the DCPD property. Consequently, a group interval on the order of 30 ft will be effective in 3D high-resolution imaging to depths of several km throughout the Irish Hills region when combined with systematic wider aperture recording at a wider group spacing. A 30-ft group interval will be effective near the DCPD where shallow velocities are generally among the highest shallow velocities found in the Irish Hills region, particularly compared to slower velocities found in Tertiary rocks in the Pismo Syncline located north of the DCPD property. However, near DCPD the AWD source became less effective because DCPD coherent noise was not effectively reduced by vertically stacking AWD impacts, resulting in low signal-to-noise at offsets > 1000 m using the AWD source near the DCPD. Consequently, for 3D high-energy high-resolution imaging of shallow structure proximal to DCPD in areas inaccessible to large Vibroseis™ trucks, mini-Vibroseis™ sources should be used to allow precise phase tuning to suppress 30 Hz coherent noise. The same approach can be used with the large Vibroseis trucks to suppress the 30 Hz coherent noise. Tuning of a mini-Vibroseis™ source should be performed to evaluate nonlinear sweeps and other sweep parameters and strategies such as slip-sweep recording. Mini-Vibroseis™ sweep tuning testing is necessary to find the optimal sweep program that provides the best-balanced resolution of structure from the near surface to several km depth within several km of the DCPD. While nonlinear sweeps and/or slip-sweep methods may be appropriate for shallow imaging with the mini-Vibroseis™ trucks, linear sweeps should be used with the large Vibroseis™ trucks to ensure good long-offset signal-to-noise to obtain good images in the 4-18 km depth range.

The large Vibroseis™ trucks operated in combination with 7220 discrete nodal receiver positions provided consistent observations of good first breaks to 8-12 km offsets in most locations, and clear first breaks to a maximum offset of 19 km. A total of > 5,800,000 good quality first-breaks were picked from a possible set of 16,700,000 first breaks from all recorded source-receiver pairs that spanned an approximately 20 km by 20 km region of the Irish Hills. Near the DCPD where plant noise was highest, the large Vibroseis™ trucks provided good first-breaks at the noisiest recording sites to at least 4 km offset. Tomographic inversion with the first-breaks was used to solve for 3D velocity structure to depths of 2 to 3 km and long-wavelength and residual source and receiver statics. The 3D tomographic approach was necessary to eliminate uncertainties in first-order statics associated with shallow steep dips and complex shallow velocity and geologic structure associated with extreme topography and thin-skinned deformation that produced irregular, and often steeply dipping reflectors.

A 2D seismic reflection profile was constructed from the Vibroseis™ -node data for a region spanning Point Buchon and Point San Luis. Consistent high-quality reflections were observed to at least 13 to 14 km depth and generally extended to 17 to 18 km depth using data in the 5-25 Hz frequency band below about 3-4 km depth. Between

Point Buchon and Point San Luis, maximum offsets of 4 to 6 km provide consistent high-quality imaging to depths of about 8 to 9 km depth. Incorporating data recorded to maximum offsets of 8 to 12 km produces consistent images to about 14 to 15 km depth. The Franciscan basement exhibited persistent reflectivity to depths of 14 to 18 km throughout most of the Irish Hills. This suggests that a good rule of thumb for this region is that the maximum image depth will be approximately 1.5 times the maximum offset in the recorded data for high-energy sources such as four synchronized 64,000 lb VibroseisTM trucks or > 3000 in³ air guns. Recording of longer-offset air gun data with onshore and offshore nodes in the region between Point Buchon and Point San Luis would improve aperture and azimuthal coverage and ensure good migration performance to depths of 8 to 14 km for the region bounded by Point Buchon and Point San Luis, the Hosgri fault to the south and the southern Irish Hills within the DCPD property to the north.

3D velocities from the tomography strongly correlate with surface geology and previously inferred shallow (1 to 3 km) geologic structure used to construct the 3D velocity model used in the 2011 illumination study. The continuously recording nodes produced clear recordings of at least 18 earthquakes at receivers located throughout the entire Irish Hills survey area, representing at least 30,000-40,000 arrival times that can be used in 3D velocity-hypocenter tomographic inversions to improve resolution of crustal velocity structure below the maximum 3D tomographic imaging depths of the active source data (2 to 3.5 km). These earthquake arrival time data will provide important tomographic constraints on deeper (> 3 km depth) crustal velocity structure than is provided by the active source data and will improve migration performance at depths > 3 km relative to industry-standard processing.

The 2011 onshore high-energy testing results indicate that in near-shore locations adjacent to the DCPD onshore large VibroseisTM sourcing should provide good signal to noise at least 4 km offshore, which would be a sufficient aperture to record the steeper dips observed in the first several km in the onshore-near-shore region proximal to the DCPD. Offshore recording of onshore VibroseisTM sources is essential to record sufficient aperture to migrate steeply-dipping structures that trend offshore from the onshore data within 8 km of DCPD.

Request 3

The choice of basic parameters such as spatial sampling interval and maximum source-receiver offset should be discussed relative to the spatial resolution required to image expected target structures at depth. For instance, what spatial resolution is required to evaluate geologic markers that might provide a measure of fault slip rate?

Response 3

The NRC places a high emphasis/importance on mapping shallow, near surface geologic investigations in order to constrain the geomorphic expression of potentially

significant and capable seismic sources. Low Energy Seismic Surveys (LESS) rather than High Energy Seismic Surveys (HESS) are the preferred tool to evaluate fault slip rate. Offsets of recent geomorphic features can be measured and dated to provide estimates for fault slip rates. These data serve as the control for estimating the rates and magnitudes for design earthquakes.

HESS surveys can provide information about the deeper geometry of seismogenic faults in the area and help constrain the source characterization of these structures. The basic acquisition parameters for the proposed 2012 HESS study are summarized in Table 5. Spatial resolution (as expressed by bin sizes) for the marine LESS studies that were conducted off of Point Buchon and in San Luis Bay were 1.56m x 3.125 m and 3.125 m x 3.125 m, respectively. Bin sizes for the HESS studies, dictated by streamer group intervals (12.5 m) and cross line spacing (100m to 150 m) are estimated to be 6.25 m x 25 – 37.5 m, respectively.

Table 5 Proposed HESS Acquisition Parameters

Survey Area	614 km ²
Source	Two (2) 3300 in ³ arrays, 9m tow depth
Recording	Syntrack
Streamer	4 x 6000m solid Sentry streamers, 100 - 150 m cross line spacing, 9 m tow depth
Channels per Streamer	468
Group Interval	12.5 m
Maximum Offset	6000 m
Shot Spacing	37.5 m flip flop (75m per source)
Shot Interval	37.5 m
Source / Streamer Location Accuracy	Source 1 -2 m / Tail buoy 7-12 m
Record Length	10 seconds
Bin Size	25 - 37.5m x 6.25m
Sample Rate	2msec
Fold	40

Request 4

The choice of towing only 4 streamers in the offshore survey should be evaluated. Typical industrial surveys deploy 10 or more streamers to improve survey efficiency (i.e., reduced acquisition time). This should be a significant issue for the proposed survey, which has been analyzed to have significant impacts to marine life, based on time exposure to the seismic source.

Response 4

Today's industry design and practice is heavily guided by the specifics of the intended target. During the past decade, the energy sector has experienced a significant move towards subsalt imaging in deep water (water depths in excess of 5000 ft, target depths in the 20,000 ft range and beyond); this operational mode is especially true for the Gulf of Mexico, offshore Brazil, and West Africa. For efficiency in regions with little or no operational hazards (such a shallow seafloor outcrops), combined with significant target depths, the industry developed a new breed of vessels, including "ramform" designs, that can tow up to 10-14 streamers with dual flip-flopping sources. In an appropriate environment, this strategy can reduce data collection time by a factor of 2 or 3—although a significant increase in the day-rate cost is realized for such vessels. Nevertheless, there are downsides to this approach. First, with respect to water depth, operations of "ramform" and similar boats are limited to water depths greater than 75 m. For comparison purposes, vessels towing 4 to 6 streamers with dual source arrays can survey into water depths of 25 m or greater. Offshore Diablo Canyon, this operational limitation would force a vessel towing 10 to 14 streamers to move offshore by an additional 2 to 4 km (from northwest to southeast). This attempt at efficiency would not only significantly increase the width of the transition zone between marine and land surveys, but would also compromise imaging quality along the Hosgri Fault (due to a migration aperture width that would overlap the intended target, creating an imaging problem at depth). Second, increasing the width of the array would also introduce unintended imaging problems, especially for shallowest sections of the crust as a wide variety of azimuths at a given location are needed to construct an image, which can be problematic (e.g., such as back tracking anisotropic effects). Third, for shallow targets, the lack of near offsets within certain bins can obscure shallow imaging of important targets such as faults. A better strategy would encompass two overlapping 3D surveys, with a narrower array (4 to 6 streamers), but shot along sail-lines from different azimuths, as is proposed for Boxes 2 and 4 in Figure 1. Ultimately, it is unsafe to use vessels towing 10 to 14 streamers given seafloor depths offshore Diablo Canyon, and the need to image structures from the Hosgri Fault toward the shoreline. Finally, the importance of both shallow and deep target imagings requires an approach that is not solely focused on the deeper subset.

PG&E's Request for Proposals (RFP) for the HESS project initially specified 6 to 12 streamers of 4 to 8 km length or offset for the HESS. The original racetrack design for the HESS was based on a minimum operating water depth of 50 m, which

acknowledged safety concerns about operating in shallow water (presence of nearshore shallow rock outcrops, kelp beds, and other navigation obstacles). Input from the IPRP suggested extending the survey closer to shore, in shallower waters. Consultation with Columbia University Lamont-Doherty Earth Observatory, operators of the *R/V Langseth*, indicated that a safe operating depth could be extended to the 25 m contour for a closer approach to shore.

The minimum operational water depth for 10 or more streamer vessels is 75 m (3x deeper than identified for the *R/V Langseth*, 25 m) due to the depths of the lead-ins both online and in the turns. Operating at these depths would preclude imaging many of the near shore targets identified in the CCCSIP. The turning radius for a ten streamer vessel is 4 to 5 km vs. 2.5 km for a four streamer vessel. With the exception of Box 2, the 10 streamer line changes for Boxes 1 and 4 could be as long as the lines themselves and would impede navigation in tight areas such as Estero Bay. Shorter turns will allow more online or production time.

Ten streamer vessels are larger, require more deck space for equipment, tend to burn more fuel due to increased resistance (introducing additional air quality issues) and require a larger turning radius. Simply stating that 10-streamer multi-channel seismic (MCS) vessels are more efficient is not applicable to all environments, especially shallow-near shore environments. In fact, there might be no efficiency in survey time realized given the above considerations. The additional risk involved in using larger vessels in shallow coastal waters would also result in additional charges and risk premiums, as well as significant expense (i.e., millions of dollars) to mobilize/demobilize these vessels and equipment to the central coastal California area.

As noted above, the original RFP specified consideration of vessels capable of towing 6 to 10 streamers. Feedback from bidding and non-bidding firms concluded that the smaller vessels with less streamers were appropriate for the constraints of this location and this survey

Request 5

The potential benefit of data acquisition over a wide (in contrast to the proposed narrow) source-receiver azimuth range should be evaluated for both image quality improvement and the ability to evaluate the orientation of maximum horizontal stress.

Response 5

Collecting 3-D using a wide-swath geometry (e.g., 10 to 14 streamer configurations) is typically seen as a negative as anisotropic effects may need to be accounted for to produce a clean, crisp image. Nevertheless, constraining crustal anisotropy can help better understand the pattern of strain (not stress) in the crust, and hence, the history of deformation. The measurement of stress in the crust is elusive and certainly not the purview of the reflection seismology technique. See response to Request 7 below. A

better acquisition strategy would consist of overlapping 3-D survey boxes (e.g., Boxes 2 and 4 in Figure 1), shot from different azimuths, using a narrow footprint of towed streamers to ensure both safety, the ability to image the shallow most sections of the crust, and estimate crustal anisotropy.

Request 6

The proposed seismic data processing flow, data processing contractor and experience should be specified.

Response 6

A number of industry contractors have been identified to conduct both the onshore and offshore seismic data acquisition and processing for the CCCSIP. All of the work performed will be in compliance with Nuclear Quality Assurance (NQA-1) requirements as stated in 10 CFR 50, Appendix B and 10 CFR 21. The proposed processing flow for the 3D Diablo Canyon project will embody the latest, cutting-edge seafloor multiple removal and seismic imaging techniques (among a myriad of recent advancements) that are currently available within industry processing shops.

Marine Navigation Processing: NCS SubSea (Houston, TX; <http://www.ncs-subsea.com/>) will be responsible for the 3-D streamer navigation using Concept Systems' Spectra, Sprint and Reflex modules to provide the highest standard of streamer navigation. The flow chart in Figure 1 illustrates the software used, QC steps, and the outputs generated in industry data exchange formats for raw (P2/94) and processed (P1/90) navigation and positioning data

NCS Subsea has worked with Fugro and PG&E on the 3D Low Energy Seismic Survey (LESS) work offshore DCP in 2010, 2011 and the upcoming 2012 PCable survey in August 2012.

Marine Seismic Data Acquisition and Processing: Contractors from well-established firms such as Fugro Geoteam (Houston, TX; <http://www.fugro-geoteam.com/>) and/or GeoTrace (Houston, TX; <http://www.geotrace.com/>) will be onboard the *R/V Langseth* during acquisition and will be responsible for all data QC and QA. This oversight will include careful inspection of trace amplitudes for all shots, potential effects of swell noise, dynamic 3D binning of data volume, etc. Table 6 and Figure 2 show an example of the data processing flow that will be used for the marine HESS. Post-cruise, the latest industry processing toolkits will be used to produce both 3D prestack time migration (PSTM) and prestack depth migration (PSDM) imagery. This processing will take place in Houston, Texas and will be contracted through an industry processing shop such as Fugro Seismic Imaging and/or GeoTrace. Recent advances in full 3D tomography and waveform inversion (FWI) techniques will also be applied to these new data.

Table 6 Typical 3D Marine Processing Flow

Reformat
De-signature to zero phase using filter designed from supplied far field signature
Bandpass filter
Resample Gun and cable static correction
Velocity analysis @ 4x4 km
Gain recovery
<i>Targeted FK filter (shallow water only)</i>
Time-frequency denoise (shot and receiver station domains)
K dealias
Tau-p mute direct arrival attenuation
3-D SRME
Velocity analysis @ 4x4 km
Time-frequency denoise (shot and CDP domains)
<i>Shot domain tau-p deconvolution and tau-p mute (shallow water only)</i>
<i>Receiver domain tau-p deconvolution and tau-p mute (shallow water only)</i>
Sort to CDP
Velocity analysis @ 2km x 2km
<i>Targeted FK filter (shallow water only)</i>
Hi-resolution radon de-multiple
Q compensation (phase only)
<i>Time-frequency denoise</i>
<i>Sort to offset domain</i>
<i>Predictive deconvolution (shallow water only)</i>
<i>Bin</i>
Tidal correction
Residual water column statics
Pre-stack time migration
Target migration lines 1 x1 km
Build migration velocity model
Interpolate to 12.5 x 12.5 m
Pre-stack time migration (curved ray)
Residual parabolic radon de-multiple
Automatic residual velocity determination (every CDP)
Normal moveout correction
Mute
Stack
<i>Low frequency boost</i>
Post stack filtering
Bandpass filter
Scaling

Onshore Seismic Data Acquisition and Processing: Onshore, Nodal Seismic (Signal Hill, CA; <http://www.nodalseismic.com/>) and Bird Seismic Services (Globe, AZ; <http://www.birdseismic.com/>) will be conducting the onshore data collection in 2012, as a continuation of onshore studies conducted in and around the Irish Hills in 2011 and as part of the Transition Zone imaging. Nodal Seismic will be responsible for operation of Vibroseis and Zland nodal data collection, and Bird Seismic will be responsible for high-resolution shallow data collection. Instrument specifications for the Zland nodals can be found at <http://www.fairfieldnodal.com/Products/ZLand/specs.html>. Onshore data processing will be overseen by Fugro Consultants, Inc. (Denver, CO; <http://www.fugroconsultants.com>). Table 7 shows an example of the onshore data processing flow. As in the case of the marine multi-channel 3D data collection, post-survey analysis will use the latest industry processing toolkits to produce both 3D prestack time migration and prestack depth migration imagery. This processing will take place in Houston, Texas and will be contracted through an industry processing shop such as Fugro Seismic imaging and/or GeoTrace. Recent advances in full 3D tomography and waveform inversion (FWI) techniques will also be applied to these new data.

Table 7 Typical processing flow for land data including a mix of source types

Reformat
Geometry build and apply
Recording delay correction (separate correction for each source type)
Refraction static calculation
Gain Recovery
Linear noise suppression
Random noise suppression
Surface Consistent Deconvolution (with minimum phase conversion for Vibroseis™ data)
First-break picking
3D tomography
Full-waveform inversion (FWI)
3D solution for long wavelength and residual statics
Refraction static application
Velocity Analysis – one-mile grid
NMO application / Mute first breaks
Residual statics
Velocity Analysis – 2 nd pass
Residual statics (2 nd pass)
Surface consistent scaling (shot and receiver)
Linear noise suppression
Random noise suppression
Migration velocity analysis – half-mile grid(inline and cross line)
Pre-stack Kirchhoff time migration
Post-migration velocity analysis
NMO – Mute – CMP stack
Post-stack filtering, noise suppression
Pre-stack depth migration

Transition Zone Data Collection and Processing: FairfieldNodal (Sugar Land, TX; <http://www.fairfieldnodal.com/>) will be responsible for the Transition Zone data collection using up to 600 Z700 marine nodes. Instrument specification for the Z700 Nodals can be found at <http://www.fairfieldnodal.com/Products/Z700/specs.html> Figure 3 shows an example of the Transition Zone 3D data processing flow. As in the case for both the onshore and marine multi-channel data, post-survey analysis will use the latest industry processing toolkits to produce both 3-D prestack time migration (PSTM) and prestack depth migration (PSDM) imagery. This processing will take place in Houston, Texas and will be contracted through an industry processing shop such as Fugro and/or GeoTrace. Recent advances in full waveform inversion (FWI) techniques will also be applied to these new data.

Request 7

The potential benefit of evaluating vertical fracture alignment, maximum horizontal stress, and directional stress inequality should be discussed. While this information is not typically used in traditional seismic hazard analysis, it does relate to the physical state of the overall seismo-tectonic setting.

Response 7

The evaluation of tectonic stress and strain are components of the seismic hazard analysis that is currently being conducted as part of the Senior Seismic Hazards Advisory Committee (SSHAC) process.

Principal stress directions can be determined from the evaluation of earthquake focal mechanisms and borehole hydro fracture data. Analysis of seismicity and earthquake focal mechanisms in the central coastal area indicates that the principal compressive stress direction, σ_1 is N15°E \pm 4° north of latitude 35°N and N47°E \pm 15° south of latitude 35°N. As seen in Figure 4, this direction is consistent with a uniform NE-SW maximum horizontal stress orientation from borehole break out data in the area and the overall pattern of recent transpressional tectonic deformation (*McLaren and Savage, 2001, Seismicity of South Central Coastal California: October 1987 through January 1997, Bull. Seismological Society of America, 91, 1629-1658*)

Request 8

The specific acquisition parameters and processing sequence of the transition zone survey should be discussed. Of particular importance would be the processing proposed to assure a high-quality seismic image after merging the transition zone data with the onshore and offshore survey data.

Response 8

The central segment of the Shoreline fault zone, between DCP and Point San Luis, lies within the Transition or Intertidal Zone, where water depths are less than 25 m. As shown in Figure 1, the Transition Zone widens south of DCP towards Point San Luis and the HESS Box 1 racetrack is oriented at an angle to the coastline. PG&E has proposed to undershoot this gap in coverage by placing a series of marine nodes on the seafloor and using both marine airguns and onshore Vibroseis™ sources. The Draft EIR specified a deployment of 600 Z700 marine nodes placed in a series of five transects perpendicular to the coast with 50 m spacing between nodes. See Figure 1 for node transect locations. Instrument specification for the Fairfield Nodal Z700 Nodes can be found at <http://www.fairfieldnodal.com/Products/Z700/specs.html>

PG&E is currently working with industry seismic processing companies to update the 2011 Illumination study, based on improved velocity models from 2011 onshore survey, to optimize marine node placement as well as onshore and offshore imaging capabilities. Recognition of environmental restrictions, including placement of nodes on hard (rocky) bottom, avoidance of protected species, etc. need to be addressed before the final node configuration is established.

A processing flow of these Transition nodal data is shown in Figure 4. Once these data are processed they will be integrated with the onshore and offshore data to develop a comprehensive 3D volume of the study area for interpretation.

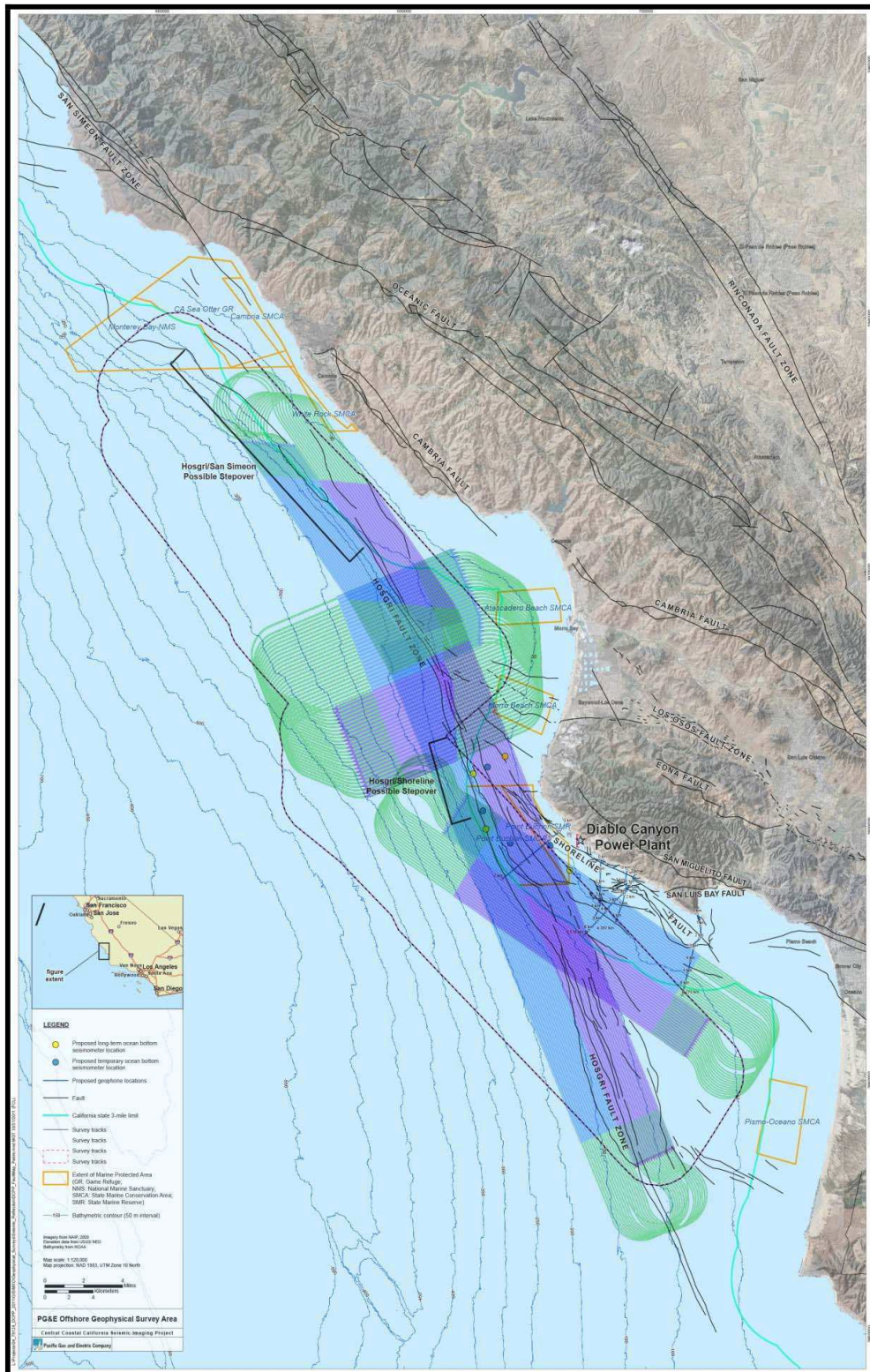


Figure 1. HESS Racetrack Diagram

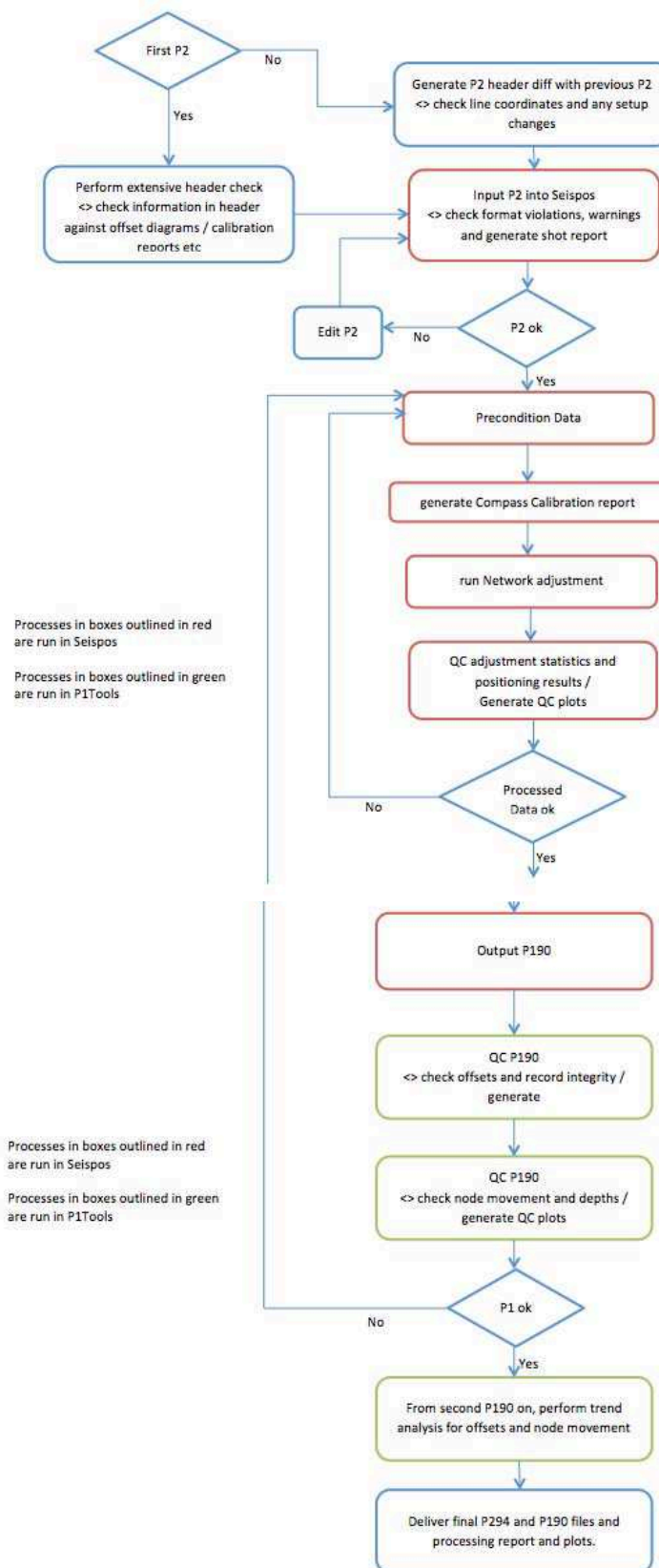


Figure 2 Typical Marine Seismic Navigation Data Processing Flow

P2/94: Industry data exchange format for raw navigation and positioning data for seismic surveying
 P1/90: Industry data exchange format for processed navigation and positioning data for seismic surveying. The P190 provides the processed position for each channel/group. SeisPos: Commercial software package for QC and processing of navigation and positioning data for seismic surveying.
 P1Tools: The QC component of the SeisPos software package.

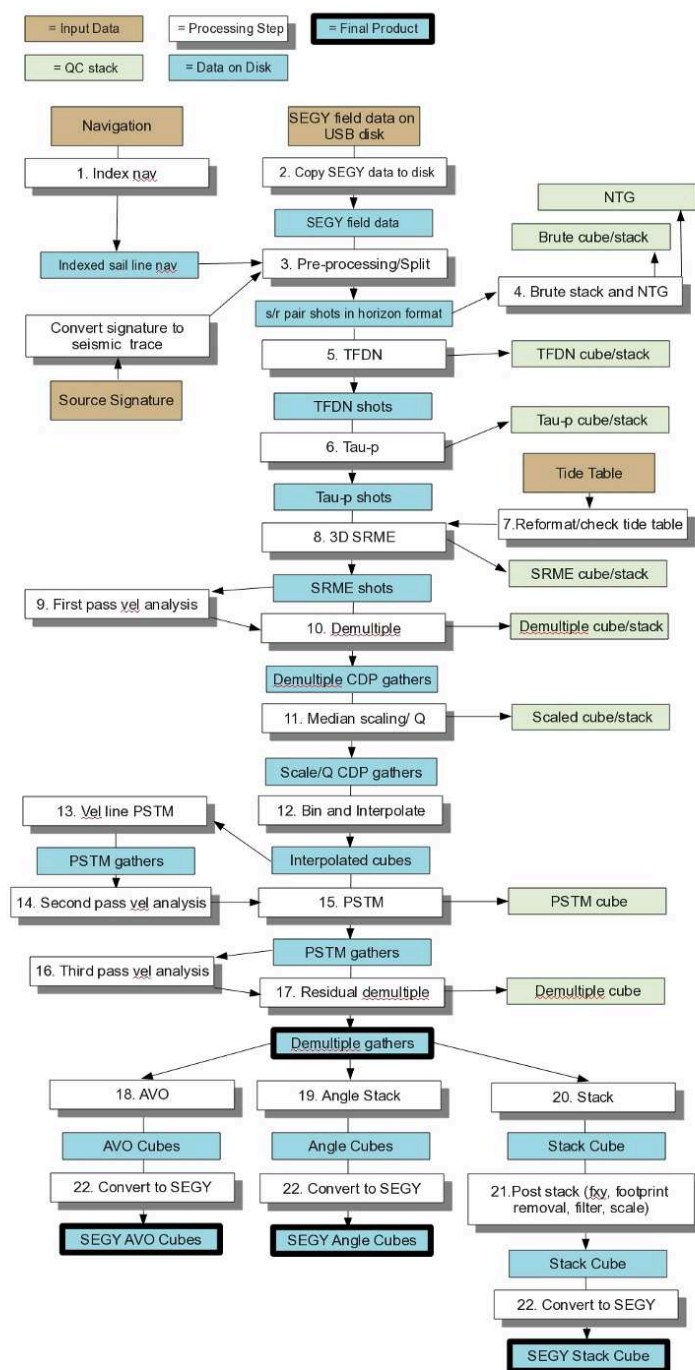


Figure 3 Typical 3D Marine Processing Flow

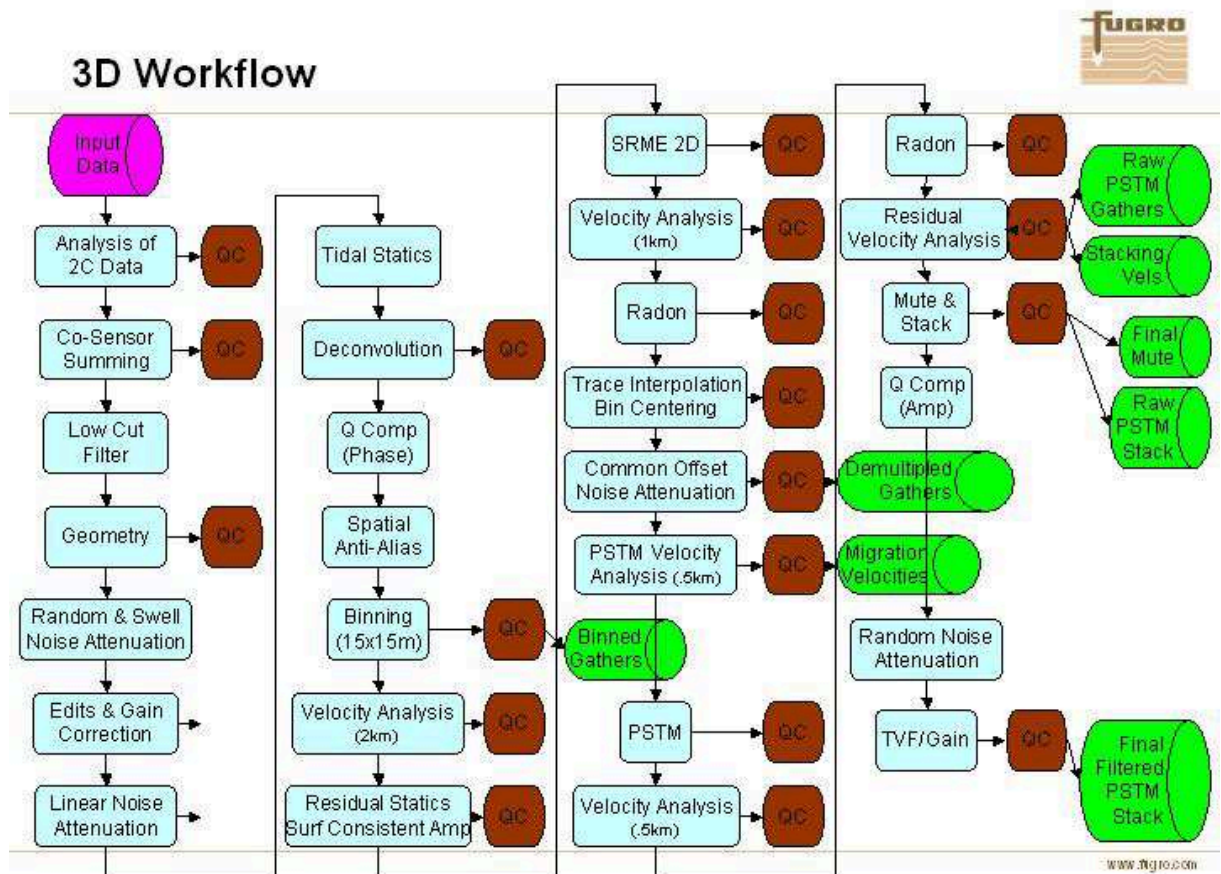


Figure 4 Typical Transition Zone Processing Flow.

Note the co-sensor summing - this is utilizing multiple components in an Ocean Bottom Node or Cable to remove receiver ghosts.

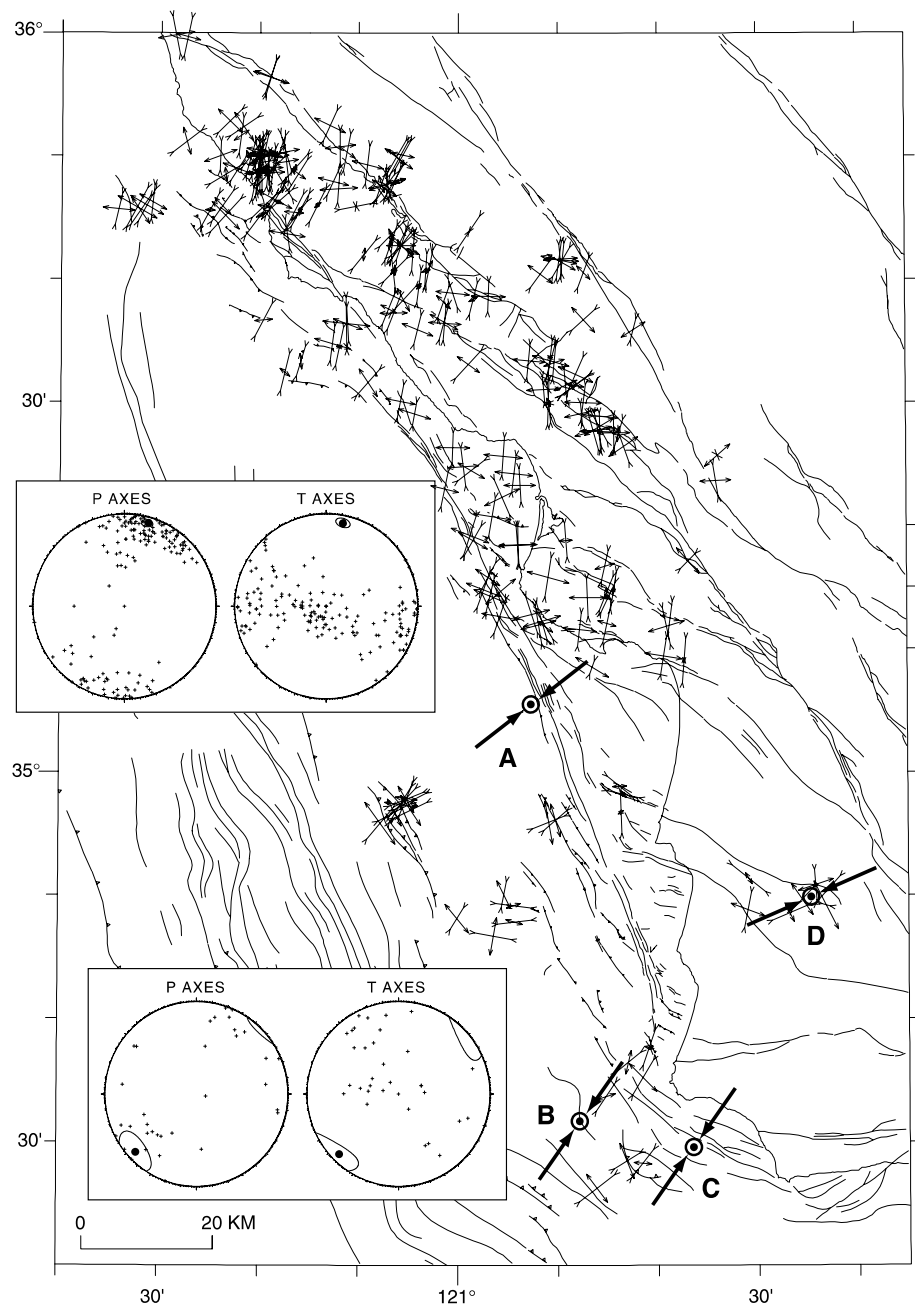


Figure 5 Horizontal surface projections of P and T axes from earthquake focal mechanisms. Encircled solid circles are locations of borehole breakout data. The two insets are stereo net plots of the distribution of P and T axes of the fault plane solutions for earthquakes in the northern and southern regions (i.e., north and south of 35°N). From McLaren and Savage, 2001.